STATE OF CALIFORNIA GRAY DAVIS, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

February 11, 2003

Agenda ID #1775
Ratesetting

TO: PARTIES OF RECORD IN RULEMAKING 02-06-001

This is the draft decision of Administrative Law Judge (ALJ) Lynn T. Carew. It will not appear on the Commission's agenda for at least 30 days after the date it is mailed. The Commission may act then, or it may postpone action until later.

When the Commission acts on the draft decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the draft decision as provided in Article 19 of the Commission's "Rules of Practice and Procedure." These rules are accessible on the Commission's website at http://www.cpuc.ca.gov. Pursuant to Rule 77.3 opening comments shall not exceed 15 pages. Finally, comments must be served separately on the ALJ and the assigned Commissioner, and for that purpose I suggest hand delivery, overnight mail, or other expeditious method of service.

/s/ ANGELA K. MINKIN by KH
Angela K. Minkin, Chief
Administrative Law Judge

ANG:jva

Attachment

Decision **DRAFT DECISION OF ALJ CAREW (Mailed 2/11/03)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing.	Rulemaking 02-06-001 (Filed June 6, 2002)

INTERIM OPINION IN PHASE 1 ADOPTING PILOT PROGRAM FOR RESIDENTIAL AND SMALL COMMERICAL CUSTOMERS

Table of Contents

I. Summary

This decision, the first of two decisions to be rendered in Phase 1 of this demand response rulemaking, adopts, with some modifications**,** a near-consensus proposal of the parties to undertake a statewide pricing pilot (SPP) designed to test time-of-use and critical peak pricing tariffs for a representative sample of residential and small commercial customers on an opt-out basis. The adopted pilot is designed to test the impact of such dynamic pricing tariffs on the usage patterns of a small sample of such customers randomly selected statewide. The decision also adopts cost recovery mechanisms for authorized Phase 1 demand response programs, including the statewide pilot. Finally, the decision provides necessary guidance to the staff and parties about designing tariffs that will make the impacts of usage changes clear to customers participating in the pilot.

II. Background

A. Procedural History

In June 2002, the Commission instituted Rulemaking (R.) 02-06-001 to provide the forum to formulate comprehensive policies that will develop demand flexibility as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment. The desired outcome of this effort is that a broad spectrum of options will be available to customers who make their demand-responsive resources available to the electric system. Thus far the Commission's rulemaking effort targets the investor owned utility (IOU) service territories of respondents Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison Company (Edison), though it may be expanded in the future to include other small and multi-jurisdictional IOUs.

The Commission set as its first task the consideration of a strategic approach to the orderly development of demand responsiveness capability in the California electricity market (OIR, *mimeo.*, p.3), and stated that it intended to coordinate this effort with related efforts of the California Energy Commission (CEC)[1], the California Consumer Power and Conservation Financing Authority (CPA), and other involved or interested state agencies.

The Phase 1 prehearing conference (PHC) was held on July 16, 2002, at which time Commission decisionmakers shared the dais with decisionmakers from the CEC and CPA. At the PHC, a procedural framework to further the cooperative strategic policymaking among the three agencies was discussed. The administrative law judge (ALJ) issued a ruling on August 1, 2002, soliciting written comments on the proposed framework, and the Assigned Commissioner's Ruling and Scoping Memo provided the final details for the interagency working model.

That model is essentially a collaborative interagency process, using three working groups. The first, Working Group 1 (WG1), comprised of agency decisionmakers (assigned Commissioner Michael Peevey, CEC Commissioner Arthur Rosenfeld, and CPA Director Sunne W. McPeak, also known as "the WG1 principals"), and supported by the assigned ALJ and advisory staff from the CPUC, CEC, and CPUC, has been responsible for shaping the rulemaking record by providing overall policy guidance to parties at key points in the proceeding. The second, Working Group 2 (WG2), is comprised of active parties who are

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[1] See, Informational and Rulemaking Proceeding on Demand Response Rates, Equipment, and Protocols, CEC Docket Number 02-Demand Response-01, issued July 9, 2002.

interested in developing demand response programs for large customers (>200 kilowatts in average monthly demand). The meetings of this group are facilitated by agency staff supporting WG1 decision-making activities. The third, Working Group 3 (WG3), is comprised of active parties who are interested in developing demand response programs for small commercial/residential customers. Like WG2, the meetings of WG3 are facilitated by agency staff supporting WG1 decision-making activities.

The Commission will issue two Phase 1 decisions. The instant decision addresses proposals for residential and small commercial customers emanating from WG3; a second decision, to be issued separately, will address tariff proposals emanating from WG2, relating to large customers.

Recognizing the importance of coordinated policy setting, as opposed to ad hoc program development, the Assigned Commissioner opted to focus heavily in Phase 1 on strategic planning, and the development of a robust policy framework as a foundation to future development of demand response programs (Scoping Memo, p. 6). However at the same time, there was a need for early action, requiring both WGs 2 and 3 to delve further into practical issues of tariff and/or program development. Early in the process, WG1 decided to focus on an exploration of the advantages and disadvantages of further pilot programs versus larger-scale program and tariff development and its timing. The assigned commissioner deferred infrastructure development and full-scale deployment options and issues to the next phase of this proceeding.

The record in Phase 1 with respect to WG3 issues was completed on January 23, 2003 when the last set of written comments was filed by WG3 participants. By that time, the three interagency WG1 principals had held noticed workshop meetings on August 26, 2002; September 16, 2002; October 15, 2002; and December 10, 2002. WG3 held eight seven noticed workshops between September 19, 2002 and November 26, 2002.

Several parties have participated actively in the workshop process and have filed written comments on WG3 issues throughout Phase 1. These include respondents PG&E, Edison, and SDG&E, as well as the Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), the California Consumer Empowerment Alliance (CCEA), the California Farm Bureau Federation (Farm Bureau), the Coalition of California Utility Employees (CUE), Consumers Union, IMServ NA (IMServ), Invensys Home Control Systems (Invensys), the San Francisco Community Power Cooperative (SF Co-op), and True Pricing, Inc. (True Pricing).

On December 10, 2002, WG3 filed its Report: "Proposed Pilot Projects and Market Research to Assess the Potential for Deployment of Dynamic Tariffs for Residential and Small Commercial Customers" (the "WG3 Report"). Parties filed written comments on this report on December 30, 2002. On January 10, 2003, the ALJ issued a ruling seeking further detail on some aspects of the December 30th Report, and parties provided written responses to that ruling on January 17, 2003. The respondent IOUs filed supplemental comments addressing expected bill impact issues on January 21, 2003. Two parties, SF Co-op and PG&E, filed supplemental written comments relating to one aspect of the WG3 Report on January 22 and 23, respectively.

No hearings were held in connection with the development of the WG3 Report. Though the Commission has categorized the proceeding as ratesetting and has acknowledged that hearings may be necessary during later stages of the proceeding, Phase 1 has proceeded as a classic notice-and-comment rulemaking. The OIR required filings from the respondent IOUs detailing their existing demand response programs and pricing options, but these filings neither framed the issues in this rulemaking, nor constituted the starting point for record development. Rather, WG1 provided specific direction to the parties at critical points in time through formally noticed meetings and rulings. The parties then took this direction, working with staff facilitators in WGs 2 and 3, and developed the proposals we address in Phase 1. Our decision-making record in connection with WG3 issues consists of respondents' formal demand response program/pricing option filings; the official transcripts of four formally noticed WG1 meetings; the rulings following those meetings and written comments thereon; and the WG3 report and related rulings and written comments.

B. Residential and Small Commercial Customer Demand Response

For purposes of this decision, demand response is broadly defined as the ability of an individual electric customer to reduce or shift usage of demand in response to a financial incentive.[2] Over the years the Commission has encouraged various forms of customer load reduction for small commercial and residential customers, including direct load control (air conditioners, water heaters, pool pumps), programmable/smart thermostats, Time of Use (TOU) rates, and efficiency investments (e.g., appliances, building upgrades, etc.) (see, OIR, mimeo. p. 3). In this rulemaking we explore a variety of programs, in

[2] See, *Glossary of Retail Electricity Rate Terms* contained in the Report of Working Group 3 to Working Group 1, R.02-06-001, p.14. The *Glossary* is attached to this decision as Attachment A.

conjunction with those listed above, designed to increase electric system demand-responsive capability.[3]

Specifically we seek to determine whether residential and small commercial customers will alter their usage patterns in response to a financial signal that is keyed to system conditions. And, if they do so, how will that change manifest itself? And finally, what are the societal costs and benefits of any such behavioral change? Well-informed decision-making requires such an informed assessment of customer response to dynamic rates.[4]

III. Working Group 3's Recommendations

The WG1 principals assigned four tasks to WG3:

- Review the current literature and field experience to identify where significant information gaps exist relative to customer experience and response to dynamic tariffs or demand response programs.
- Recommend a strategy to fill these gaps including, but not limited to, additional market research, modifications to existing pilots of dynamic tariffs, or the design of new pilots to test dynamic tariffs.

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[3] This proceeding is focused on the electric system, although the working groups have been authorized to explore metering cost/benefit issues relative to the dual-fuel respondent utilities during the pendency of this proceeding (ALJ's Ruling Following the First Meeting of Working Group 1, mimeo p. 15).

[4] A dynamic rate is a rate in which prices can be adjusted on short notice (typically an hour or day ahead) as a function of system conditions. A dynamic rate cannot be fully predetermined at the time the tariff goes into effect; either the price or the timing is unknown until real-time system conditions warrant a price adjustment. *Examples: real-time pricing (RTP). Critical peak pricing (CPP).* See, *Glossary of Retail Electricity Terms,* Working Group 3 Report, p. 14.

- Propose an implementation plan and schedule to fill the gaps.
- Describe how the results from the pilots will be used to conduct further analysis in Phase 2, which is designed to assess whether these new dynamic tariffs and the infrastructure to support them are cost effective to both participating customers and all ratepayers.

In meeting its charge, WG3 presents a near-consensus proposal (the Statewide Pricing Pilot or "SPP") which integrates several pilot proposals presented over three months' time by various participants in the working group process. WG3 recommends that the respondent IOUs conduct market research to refine the dynamic rate and control technologies to be tested and then implement the SPP to test TOU and Critical Peak Pricing (CPP) tariffs for a representative sample of residential and small commercial customers on an opt-out basis. Most of the WG3 participants[5] support the SPP "as is" or with minor modifications.[6]

There are two alternative or complementary pilot proposals. One is presented by Invensys, a meter service provider who proposes to test an advanced interactive technology treatment and dispatchable demand response offerings. The other is presented by IM Serv, which proposes to test the concept of providing customers with cash incentives (based on transmission and distribution (T&D) savings) for a combined integrated demand response/enabling technology and advanced metering open architecture

[5] Supporters include PG&E, Edison, SDG&E, ORA, CUE, TURN, the SF Co-op, CCEA, Consumers Union, Siemens, and Distribution Control Systems, Inc. (DCSI).

[6] See Appendix A to the WG3 Report for dissenting views on certain issues.

solution directed toward reducing demand on constrained transmission and distribution circuits.

A. Summary of the Statewide Pricing Pilot

1. Research Objectives

The SPP is designed to address specific information gaps identified by WG3 after reviewing information gathered on over 100 experiments and programs conducted in California, other states, and internationally. This information shows that consumers do respond to time-varying prices by reducing usage during expensive time periods and shifting it to inexpensive periods. However, most of these studies occurred outside California and the bulk of them were conducted more than a decade ago. Much has changed since then in California, including the introduction of additional residential rate tiers and rate surcharges and a utility supply portfolio that combines utility-owned generation, long-term contracts signed by the Department of Water Resources (DWR), and spot market purchases. It also appears that customer demand response to time-differentiated prices varies by class (residential vs. small commercial), usage level, appliance holdings, climate, presence and absence of automated control capability, and program duration. However there is a general lack of information about small commercial customer response to CPP, and residential customer response to CPP without automated response technology.[7] (WG3 Report, Section 2.1).

[7] Such technology allows the customer to pre-program a control strategy to be automatically activated in response to a dispatch, but the use of this technology adds cost/benefit issues to the overall assessment (See, generally, WG3 Report, Section 2.1).

To address these significant information gaps, WG3 proposes a statewide pilot designed to gather specific information about price elasticities and customer preferences, testing the following features: California's current regulatory, energy, and economic climate; critical peak pricing with and without automated response; preferences of small commercial and residential customers; a variety of electricity usage levels, appliance holdings, and climate zones; and voluntary rates. Key issues to be addressed in the pilot are (1) the impact of new rates, information, and technology treatments on the average participating customer; and (2) customer preferences for rate and other treatment options and level of program participation. (WG3 Report, Section 2.7; Section 3.1.1.)

2. The Statewide Pricing Pilot's Basic Features

The SPP, which will run through the end of 2004, will measure the impact of three specific time-varying rates on customer electric consumption and coincident peak demand: TOU rates; fixed critical peak pricing rates (CPP-F); and variable critical peak pricing rates (CPP-V). TOU rates feature higher prices during one or two peak periods and lower prices during an off-peak period. CPP-F rates resemble a standard TOU rate on most days of the year, but have a fixed higher rate during ten to fifteen predetermined days of the year. Customers receive day-ahead notification for all CPP-F days. CPP-V rates differ from CPP-F rates in that the critical peak period may be called on the day of the event, and it is not confined to a fixed number of hours that are known in advance.

The SPP's primary target is residential customers, since earlier experiments show that they demonstrate much greater responsiveness to time varying rates than do commercial customers. However, the SPP breaks new ground by also including small commercial customers (WG3 Report, Section 3.1.2.2). Pilot participants will be drawn from four climate zones including customers of all three respondent IOUs. In one case, in response to SF Co-op's proposal, the pilot will include a module focused on a specific sub-population within the PG&E service territory.

The SPP will test three different rate structures: a static TOU rate, a CPP-F and a CPP-V. It will also, at a minimum, assess the impact of one information treatment and one complementary technology treatment. The specific characteristics of these treatment options will be refined based in part on input from ex ante market research, taking into account practical issues associated with implementation capabilities and schedule.

A static TOU rate can be implemented using manually read standard TOU meters, whereas a dynamic rate requires daily reads, and thus, remote meter reading capability. In testing three different rate structures, including both static (TOU) and dynamic (CPP-F and CPP-V) rate structures, the SPP will attempt to answer the question whether the incremental benefits of a dynamic rate are sufficient to offset the incremental costs when compared to both the existing rates as well as to a traditional static TOU rate (WG3 Report, Section 3.1.2.4).

The SPP will also provide data about the impact of information presented to participating customers, both general information and education about rates and other options available to the customer, and more specific and personalized information provided to the customer as input to the customer's ongoing usage decisions. In connection with the latter information type, the SPP will include a special feature suggested by SF Co-op, known as the "Track B pilot." One hundred electric customers residing in the Bay View, Hunters Point, and Potrero Hill districts of San Francisco (home to two aging power plants which generate above-average levels of air pollutants) will be randomly selected and provided with information about the economic and environmental consequences associated with peak power use, and informed of the potential to reduce reliance on a locally polluting power plant through adoption of the CPP-F tariff. These track B pilot participants will receive educational information regularly and periodically to reinforce this message, and will be contacted via various communication means when the critical peak periods are occurring. The SPP will include a control group of 100 electric customers randomly selected from another Bay Area community situated near a known and publicized environmental hazard, with similar socio-economic and demographic characteristics, and similar climatic and other demand-driving conditions. The Track B pilot will provide data about how environmentally oriented information, provided to a population with heightened sensitivity about air quality issues, may increase responsiveness to CPP-F.

Studies have shown that dynamic rates combined with enabling technologies can produce substantial load shifting but that substantial load shifting can also occur without such devices. Enabling technologies can be installed at the customer site to control automatically the operation or cycling of one of more domestic appliances in response to a price or emergency signal. These technologies "enable" the customer to respond to signals by pre-programming control devices that will reduce electricity loads even if the customer is not at home. The SPP will examine relative responsiveness to dynamic rates with and without such technology, with further details to be developed during ongoing working group discussions. One current idea under exploration is to offer CPP-V customers a choice of technologies including direct load control, timers for swimming pool pumps, and smart thermostat technology that is currently being tested by SDG&E and Edison under existing pilots. While several WG3 participants propose more sophisticated automated control technologies involving always-on gateway systems which would facilitate incentive-based systems, the majority of the WG3 participants agree that, at this time, the SPP should focus on dynamic rates rather than incentives because (1) this will reduce implementation complexity and allow the SPP to begin collecting Summer 2003 data, (2) such advanced technologies appeal to very high use customers and as less important to the general decision regarding wide scale deployment of advanced metering, and (3) the simpler technologies are sufficient to support the CPP-V rate being tested.

The 2,575 customers participating in the SPP are assigned to various tracks[8] which are designed to simulate the effects of a large scale roll-out of time-varying prices. Track A is a random sampling of each respondent IOU's residential and small commercial customers from various climate zones; each customer is placed on a time varying rate or a control rate depending on their allocated cell. Those customers on a time varying rate could opt out at specified time(s). Track B is the SF Co-op pilot previously described, which also involves a random customer selection. In addition to those customers randomly selected, 400 of the 2,575 pilot participants are taken from the ongoing Smart Thermostat pilot being conducted in the SDG&E and Edison service territories under Assembly Bill (AB) 970 (Stats.2000, c.329). These customers have opted into the program, which provides them financial incentives in exchange for agreeing to raise their thermostat setting by a few degrees during critical peak periods. For

[8] See "Table 3-2. Sample Design of the Statewide Pricing Pilot" extracted from the WG3 Report and appended to this decision as Attachment B.

these customers, the program would be changed so that the financial incentive is not given to them in the form of a cash payment, but is structured around a CPP-V price. While not randomly selected (and thus not providing usage change data that would be generalized to the population from which they are drawn), the analysis of these customers' usage changes would provide useful data about how "opt-in" customers respond to pricing incentives in the presence of enabling technology (WG3 Report, Section 3.1.2.5).

3. The Statewide Pricing Pilot Implementation Plan and Schedule

At the present time, and continuing in varying degrees over the next several months, several implementation activities are required. These include finalizing and obtaining approval for the conceptual pilot design and associated tariff design; completing the sampling plan and drawing the sample; designing and implementing the customer contact plan (notification of meter installation, pilot enrollment, etc.); acquiring and installing meters; undertaking customer education and notifying customers of their participation in the pilot; developing and undertaking customer surveys; developing data retrieval, data framing, and billing capabilities; educating employees; and evaluating the data, a process that will occur throughout the pilot. The evaluation plan is key to determining the extent to which customers respond to time varying prices, in the presence and absence of complementary information and technology treatments, and to assess how responsiveness varies with customer characteristics, weather and other determining factors. The pilot will also provide information about customer opt-out rates.

4. Statewide Pricing Pilot Costs

The total cost for the SPP, as proposed, is $9.6 million. These costs cover such items as project management, customer education, customer notification and contact tracking, meter hardware and installation; meter reading and communication; data retrieval, validation, and management; billing system interface development and implementation; information treatment; enabling technology treatment; and a variety of planning and evaluation activities. Some of these costs are fixed, while others are primarily variable.

WG3 estimates that the average variable cost per residential customer pilot participant will equal $2,500 and about $3,000 for each commercial customer participant, for a total variable cost figure of $7.1 million (WG3 Report, Tables 3-2 and 3-3).

The fixed costs of the SPP are $2.5 million. They include $800,000 for *ex ante*, concurrent and *ex post* market research activities; $300,000 for refinement of the sample design and the rate, information and technology treatments; $750,000 for impact evaluation activities; and $650,000 for project management activities to be undertaken by the three respondent IOUs. (WG3, Section 3.1.4.)

5. Market Research

Pilots of this size require a market research program in order to ensure that the pilot is understandable to customers and does not impose undue hardship on participants. Market research can provide unique insights into customer needs and preferences and help fine-tune rate treatments offered in the pilot. It can also determine the optimal amount of information that should be provided to participants, and the specific types of enabling technologies that should be utilized.

WG3 recommends that a limited amount of market research be conducted prior to the decision approving the SPP, given the lead time necessary to develop tariffs, choose samples and install meters and other enabling technologies and the narrow window of time prior to Summer 2003, when the SPP should be up and running. There are key questions to be explored during this period, including: How can the concept of time-varying pricing be explained to customers? What features of TOU and CPP pricing appeal (or do not appeal) to customers? How can time-varying options be designed to maximize customer acceptance? What should be the length, timing and number of peak periods? What combinations of peak and off-peak prices can customers cope with? Can customers respond to CPP pricing without enabling technologies? Is there any customer interest in day-ahead or hourly real-time pricing? What information treatments are desirable/acceptable? What types of notification procedures are desirable/acceptable? What minimum information should be made available to customers? Under the direction of the WG3 staff facilitator, this *ex ante* market research is underway now, employing approximately a dozen focus groups throughout the state. The estimated cost of the *ex ante* phase is $100,000.

Once the SPP is underway, additional market research will be conducted to determine whether rate features, information treatments, and technology treatments are working optimally. Using a variety of survey methods, this concurrent market research will also attempt to measure customer understanding of, and satisfaction with, the SPP; it will also determine problem areas and provide remedies where possible. (WG3 Report, Section 3.1.4.2.) The estimated cost of the concurrent market research phase is $500,000.

Finally, participating customers will be surveyed at the conclusion of the pilot (*ex post* market research) to obtain their views about the specific rate they were on, and the information and technology treatments they experienced (WG3 Report, Section 3.1.4.3). The estimated cost of the *ex post* market research phase is $200,000.

6. Cost-Benefit Analysis of the Statewide Pricing Pilot

WG3 believes that the real benefit of the SPP is the improved decision making that will result from the pilot's narrowing of the range of uncertainty about the net benefits of dynamic pricing. This value is estimated in the WG3 report to exceed, twenty times, the pilot's proposed $9.6 million cost. (WG3 Report, Section 3.1.5). However, in response to WG1's request that WG3 estimate the net benefits of the peak load reductions caused by SPP, WG3 indicates that the pilot is unlikely to show positive net benefits because communication and metering costs are higher by an order of magnitude during the pilot phase. Assuming gross SPP costs of $9.6 million, and gross benefits of $0.155 million[9], as proposed, the SPP reflects an annual net cost of $9.4 million. (See WG3 Report, Section 3.1.5.3.)

B. Alternative Pilots

Two alternative pilots are presented by two parties who were active in the WG3 process.

1. The Invensys Pilot

The first proposal is presented by Invensys, and is designed to test the effectiveness of an advanced interactive technology treatment and Dispatchable

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[9] SPP customers are projected to lower their peak demand in year 2003 by 1.5 megawatt (MW), from a base level of 14.5 MW. This is projected to yield gross benefits of $0.155 million.

Demand Response offerings. The pilot assumes that a subset of 20-35% of households in the state represent a target set that could represent substantial loads in a dispatchable demand response setting. The Invensys pilot has two options:

> Option 1 is a stand-alone pilot that would supplement the SPP. It would include 3,000 "points" and test 37 participants per cell (based on 3 climate zones, 3 social demographic segments, 3 marketing programs, and 3 incentive treatments). Invensys envisions that it would undertake a turn-key program, including recruitment, installation, and operation. The pilot includes software program monitoring and "power plant" interface; consumers would have access to their home control and energy information through a variety of easy-to-use interfaces. The cost per pilot is $1,500 per "point," excluding additional program evaluation costs estimated to be $1 million to $3 million per pilot. Invensys estimates the average peak load reduction per qualified target home at 2.3 kilowatt (kW) (a figure that requires verification), resulting in an estimated cost effectiveness for the pilot of $652 per kW, with an estimated customer churn rate of less than 2% per year. (WG3 Report, Section 3.2.2.)
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> Option 2 proposes that 300 points be added as cells to the SPP. This would test enabling technology for a dispatchable incentive. As with Option 1, Invensys would provide a turn-key program, including recruitment, installation and operation. Option 2 differs from Option 1 because it represents a limited test of dispatchability, and focuses instead on supplementing the SPP tariff with a technology treatment. The Invensys pilot differs from the SPP in that (1) it tests dispatchable demand response programs using a fully functional advanced technology platform; and (2) it includes additional load types over HVAC and a platform capable of later including appliance loads.

2. The T&D Control Pilot

A second pilot proposal, known as the T&D Control Pilot Proposal, is submitted by IMServ. The IMServ pilot is not meant to replace other pilots, but to complement them. It would test the concept of providing incentives (based on T&D savings) for a combined integrated demand response/enabling technology and advanced metering open architecture solution directed towards reducing demand on constrained transmission and distribution systems. Pilot features include: wider participation, including direct access customers; a focus on reducing T&D constraints, which may not coincide with critical peak generation; a focus on developing sufficient information for a full-scale effort in Phase 2 of this proceeding featuring open architecture meters that could be accessed through multiple technologies such as radio and telephone; and customer-specific solutions ranging from web-based information and feedback systems to advanced automated facility load controls. The pilot's target population includes both direct access and utility customers, located in areas where there are critical T&D constraints. Such customers could be above and below 200 kW.

IMServ asserts that long-run program costs will approach revenue neutrality since the program's emphasis is to reduce T&D costs. The cost of the pilot will be controlled by the cost benefit ratio (still undetermined) of program cost to expected benefit. T&D benefits must be developed by the local utility. While it has not engineered a typical system, IMServ calculates that an advance meter with a web-based customer information system could cost $1,000 to $3,000 with additional operating costs (WG3 Report, Section 3.3.10)

C. Dissenting Viewpoints

Four parties, TURN, ORA, PG&E, and SCE, took advantage of the opportunity to submit dissenting viewpoints in the WG3 Report.

1. TURN's Concerns

TURN[10] does not support universal deployment of advanced meters, but believes there may be specific applications of dynamic pricing and advanced meters that provide meaningful demand reduction and participant savings for small customers. However, it feels that inquiry has been sacrificed in this rulemaking for an "all or nothing" approach. Nonetheless TURN does not oppose the SPP and hopes that it will produce meaningful data that will steer decisionmakers in the correct direction. If the SPP results show that only specific advanced metering and dynamic pricing applications are cost effective, decision makers should not leap into a multi-billion dollar decision to invest in system deployment. Further, in Phase 2 the Commission should evaluate alternative methods of cost recovery for advanced metering.

TURN believes that most small customers will not benefit from TOU pricing, arguing that smaller customers that might benefit from time-differentiated pricing due to their load shapes don't have enough load to shift to pay for the meters. In addition, TURN states that metering costs are traditionally allocated mainly to small customers as customer costs, which utilities prefer to recover as fixed customer charges – further dampening customer incentives to shift load. TURN acknowledges that the preliminary business case presented by PG&E during WG3 meetings is not part of our Phase 1 decision-making process, but believes that still preliminary analysis demonstrates nothing more than the notion that universal deployment is very uncertain at this point.[11]

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[10] See WG3 Report, Appendix A.1, Dissenting Comments of TURN.

[11] TURN notes that in 1997 the environment was decidedly more conducive to the realization of advanced metering benefits because, unlike the present situation, utilities

Footnote continued on next page

TURN believes that WG3 has ignored many tools already available to achieve demand response. In particular it notes that for close to 25 years, inverted tier rates have significantly reduced overall energy usage by sending a significant conservation message. Inverted tier rates may also provide associated peak demand reductions, which TURN regards as a more valuable resource than mere load shifting.

TURN also believes that air conditioner (A/C) cycling programs have provided some of the most reliable demand reduction in the nation. Edison has had a successful program for many years. The Independent System Operator has always dispatched it before other demand response programs, especially those based on price response. According to TURN, A/C cycling programs on average result in 2.3 kW/unit of reliable demand response compared to current forecasts of 0.9 kW/unit in demand reduction in SDG&E's more expensive Smart Thermostat Program. In response to WG1's desire that WG3 develop some alternatives to a Summer 2003 "quick win," TURN states that the greatest potential lies in requiring the utilities to ramp up their existing A/C cycling programs (WG3 Report, Section A.1.3). We note that A/C cycling programs were originally not part of the scope of this proceeding, since they were being addressed in our interruptible rulemaking (R.00-10-002). Now that that proceeding has been closed, it may be appropriate to revisit A/C cycling's contributions to demand response here. In addition, we note that due to

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had to purchase 100% of their power from the power exchange. Nonetheless, at that time the Commission decided that the risk of deploying a system wide automatic meter reading system in Edison's service territory should be assigned to shareholders rather than ratepayers because the system costs greatly exceeded system benefits without inclusion of price signal and direct access benefits (D.97-05-039).

Edison's existing large A/C cycling program, we already have a great deal of information about customer response to A/C cycling programs. Our focus in this proceeding and this decision is on gathering further data on customer response to various programs and tariffs as yet untested in California.

Finally, TURN believes that the Commission should address meter ownership/cost recovery issues and evaluate the elimination of the incumbent utilities' competitive advantage regarding meter installation in Phase 2 of this rulemaking. By ALJ Ruling in Application (A.) 99-06-033, the Commission has requested parties' views on whether the latter issue should be moved to Rulemaking (R.) 02-06-001.

2. ORA's Concerns

ORA[12] supports the SPP, but suggests that its "voluntary opt-out" feature be changed by offering customers a monetary incentive to participate. It believes that an incentive of $100 would add about 3% to the cost of the SPP and would still preserve the statistical and legal integrity of the test. Such a payment should not affect customer behavior once customers are on the tariff.

ORA also recommends that the SPP be modified to include an hourly pricing treatment beginning in October 2003, in coordination with the IOUs' efforts in WG2 to develop a production scale hourly pricing tariff. Hourly prices should not be ruled out for residential customers because forecasts of wholesale prices over the next four or five years indicate that price variation by TOU period in California will not be much higher than they were in Puget Sound's territory.

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[12] See WG 3 Report, Appendix A.2, ORA Recommended Improvements to the Statewide Pilot Program.

However, there may be temporary price spikes hidden by the level of aggregation in TOU, and even CPP, rates. ORA notes that studies indicate TOU rates only capture about 10% of real-time price variation, whereas a day-ahead hourly price can capture 60 to 70%. For this reason, hourly pricing should be given serious consideration (WG3 Report, Section A.2.2.1).

3. PG&E's Concerns About the Invensys Alternative Pilot Proposal

The Invensys technology treatment is virtually identical in concept to that proposed in the SPP, except that Invensys proposes to dispatch loads other than air conditioning using a prototype "gateway" technology; however, for a variety of reasons, PG&E does not support the Invensys alternative.[13] First PG&E is concerned about the additional cost of the alternative, as it is interested in keeping pilot costs to a minimum while maximizing the information the pilot produces. Key to this is keeping the number of pilot customers and technology treatments to a minimum. Second, the alternative focuses on the dispatch and direct IOU control of many customer loads. Thus the alternative would not focus on gaining insight about customer response to dynamic pricing, but would require more complex rate structures and incentive payments. Third, PG&E believes that no CPUC-ordered demand response pilot of this type should be implemented based on the deployment or selection of a single manufacturer's technology. A proper technological assessment is required before such a decision. In sum, PG&E maintains that the alternative pilot will not add significant value to what the SPP will provide, and the complications of

[13] See WG3 Report, Appendix A.3, PG&E Comments.

implementing the pilot will jeopardize the goal of having a pilot in place to collect Summer 2003 data (WG3 Report, Section A.3.1).

4. Edison's Concerns About Both Alternative Pilot Proposals

Edison[14] believes that the Commission lacks the information to determine whether the Invensys-proposed technology treatment is superior or inferior to any of the other alternatives, and that making a vendor-specific award is imprudent in the absence of a technological assessment. And while Invensys claims that its implementation costs are less than those associated with the IOU pilots, there is no information supporting this claim. Also the IOU pilots are intended to provide the data necessary to measure and evaluate load response base on a variety of conditions; thus the pilot technology options proposed by the IOUs are not necessarily representative of the technologies that could be implemented on a wider scale. The IOU pilots focus on A/C load since that remains the largest contributor to peak demand. Finally, Edison argues that there are numerous rate treatments that could be considered, including a reward system such as that proposed by Invensys, but that rate treatments should be limited in order to limit pilot costs (WG3 Report, Section A.4.1).

Edison also opposes the IMServ T&D Control Pilot proposal that would offer customers T&D credits for reducing T&D costs. Edison believes the alternative proposal is insufficiently detailed; that currently it is premature and inappropriate to work towards developing a T&D incentive-based program, since the another Commission proceeding (R.99-12-025) is delving into related

[14] See WG3 Report, Appendix A.4, SCE Comments on the Invensys and IMServ Pilot Proposals.

T&D issues; and customers who reduce demand or move demand off-peak already benefit from reductions in distribution costs due to reduced peak or non-coincident demands (WG3 Report, Section A.4.2).

IV. Discussion

A. Modifications to the SPP's Basic Features

While we appreciate that WG3 has worked most diligently to produce a near-consensus pilot proposal, we will modify the SPP in some respects before approving it. Our modifications focus on the SPP Track B and SPP Track C pilots, customer participation in the SPP, and the SPP's information and technology treatments. As noted more specifically below, some of the required modifications will impact the timing of certain SPP elements and the SPP's cost.

There are some suggested revisions to the SPP and the overall Phase 1 approach that we do not adopt. For example, TURN, which generally supports the SPP, has raised a fundamental question about whether many residential customers consume energy at sufficient levels to make it cost effective for them to shift load. This is an important issue, but it is exactly the type of inquiry that cannot be assessed without obtaining additional empirical data of the type the SPP is designed to generate. And it is not a reason to disapprove the SPP as currently presented. If it develops that the SPP demonstrates that low usage customers cannot benefit from dynamic tariffs, that will be the time to focus on other alternatives for such customers. That said, we are not in any way ignoring those alternatives in this proceeding. Indeed we are prepared in this proceeding to seriously explore making more demand response available by aggressively advancing existing A/C cycling programs, and promoting new ones, as discussed below in connection with newly enacted Pub. Util. Code § 2774.6.

We also decline to broaden the dynamic tariff offerings included in the SPP to include an hourly pricing treatment beginning in October 2003, as proposed by ORA. While this idea may have merit in the future, it is simply too costly and speculative at this point to include this option in the SPP. Once a reliable hourly-price is available and we have more information about potential customer interest in such an option, it is possible we may revisit this decision and decide to test an hourly pricing option for small customers in Phase 2 of this proceeding.

1. The Track B Pilot Proposed by SF Co-op

As discussed, the Track B pilot sponsored by SF Co-op, is a strong community-based effort targeting low-income customers in an urban area suffering air quality problems due to aging power plants. Though a relatively small number of customers are included in Track B, we believe there is merit in testing this community-based approach because it will test the benefits of providing environmental education associated with peak power usage in areas suffering from poor air quality. SF Co-op also notes that Track B specifically addresses TURN's concern that residential customers may not have sufficient levels of consumption to cost effectively shift power, because Track B is designed to determine how environmental motivations, combined with low-cost information tactics, will affect household electricity use behavior.

We will hold the respondent IOUs responsible for ensuring that every SPP cell, not just that included in Track B, has a viable control group. And we are concerned that, while WG3 will include a control group of 100 customers from another similarly situated Bay Area community, the selected control group for Track B must be representative of the Track B participants. To that end, it must include similar households (including a sufficient number of low-income participants) who face the same environmental degradation and/or reside in transmission-constrained areas. We expect this concern to be addressed by PG&E.

There is some disagreement between SF Co-op and PG&E over pilot funding and SF Co-op's involvement in the pilot.[15] While the Track B pilot was developed as part of the SPP, which will be undertaken by PG&E and the other respondent IOUs, SF Co-op believes that funding its collaboration with PG&E, particularly in the areas of properly developing and analyzing the pilot, is necessary to ensure the pilot is implemented cost-effectively. SF Co-op acknowledges that it will work under the project management and analytic guidance of PG&E, but it also believes that as a community-based organization, it has a unique capacity to develop, implement, and analyze the project, most notably its educational and information-gathering features. To that end, SF Co-op requests $142,000 for its role in pilot development, implementation and analysis, which it argues is less than 25% of the IOUs' proposed funding level.[16] In response, PG&E notes that the IOUs are ultimately accountable for justifying the cost-effectiveness of implementing funds, including those related to PG&E's compensation of SF Co-op consultants who will be working on the Track B pilot under PG&E's project management. PG&E also notes that the current SPP budget includes at least $625,000 for the Track B pilot, and some portion of the evaluation budget for the entire SPP also covers Track B pilot evaluation. To the extent that SF Co-op's expertise will be used, the cost of funding those activities

[15] The issue was detailed in supplemental comments filed by SF Co-op and PG&E on January 22 and 23, 2003, respectively.

[16] This claim is not entirely correct, as the $625,000 budget includes $525,000 related to metering and billing activities, activities SF Co-op will not be involved in.

is included in the current budget at a figure of approximately $100,000. So this dispute essentially raises the question whether the Commission should authorize the $142,000 requested by SF Co-op or allow PG&E, in its capacity as project manager, to compensate SF Co-op's educational and implementation activities at the appropriate level.

It should be clear that we are holding PG&E responsible for the success of the Track B pilot. There is no dispute between these parties as to PG&E's role as project manager. There is no dispute between them regarding SF Co-op's crucial SPP role. PG&E will compensate SF Co-op for these efforts. Thus we will not specifically authorize SF Co-op's $142,000 request.

2. The Track C Pilot

The Track C pilot consists of over 400 customers currently participating in the ongoing Smart Thermostat program being conducted in the Edison and SDG&E service territories under AB 970. Unlike others participating in the SPP, these customers will not be randomly selected. Essentially they will be "borrowed" from an existing experiment. There they are volunteers, compensated on an incentive basis, although the current incentive mechanism will be altered for purposes of SPP. Track C of the pilot will test whether these customers will give up the current guaranteed incentive payment in favor of CPP-V tariff option. Track C is one way SPP proponents propose to test enabling technologies in conjunction with CPP tariffs, and thus the proposal has great value. Track C also augments existing program infrastructure, thus minimizing incremental cost. We do have one concern about the validity of the results of the Track C pilot, given that the customer recruitment method will differ from that in Tracks A and B. To ensure valid results, we expect respondents to undertake additional effort in the form of alternative recruitment in order to make Track C a more representative sample and ensure adequate control groups for comparison purposes, or propose a method of validating these results.

3. Customer Participation in SPP

While randomly selected customers will have the opportunity to "opt out" of the SPP, the IOUs prefer that customers remain in the pilot for a minimum of four months prior to opting out.[17] But this issue will not be decided definitively until the current customer focus group effort is completed. In its dissenting remarks in the WG3 Report, ORA proposed a $100 incentive payment to encourage participation. The IOUs now favor the payment of a $100 "appreciation bonus" at the end of the four-month commitment period, i.e, the end of the summer of 2003. This would not be an inducement to participate, but compensation for any inconvenience the customer experiences for being included in the pilot. We agree with this approach. Further, the IOUs are making efforts to minimize the number of situations where a customer opts out after a meter is installed.[18]

CCEA, which is actively participating in enrollment issues, notes that there are at least four enrollment goals the SPP must meet: 1) the SPP must enroll a

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[17] Edison believes the Commission should provide guidance concerning how Rule 12 will interplay with the SPP (Edison Comments to WG3 Report, pp. 8-10). In general terms, this tariff provision requires respondents to inform potentially affected customers that new or revised rates are effective, and specifies the conditions or situations under which such customers may choose to change rates. Since the SPP is an experiment limited to a small group of randomly selected customers, we do not believe that Rule 12 requires that all residential and small commercial customers be notified of the SPP, nor do we believe Rule 12 has any impact at all on a customer's decision to participate in, or opt out of, the SPP.

[18] IOUs; Joint Response to the ALJ's January 10, 2003 Ruling, pp.18-20.

representative sample of customers to maintain the integrity of the experimental design and ensure the validity of the experimental results; 2) the SPP must maintain a high level of customer satisfaction; 3) the SPP must promote retention of the participants for at least one summer; and 4) the SPP must minimize costs. CCEA suggests that the ideal way to achieve these goals is to select a statistically random sample and persuade those selected to participate voluntarily. This approach, combined with the "appreciation bonus," will enhance the voluntary aspects of this pilot's enrollment process, even though, technically speaking, the process allows the unhappy customer to "opt out." Those WG3 participants who are working on SPP enrollment issues should follow this approach.[19] [20]

4. Information Treatments

We are concerned that the SPP, as proposed, does not explicitly state what types of feedback will be made available to customers regarding the kW or dollar impact of their curtailment actions on either a daily or monthly basis. We are concerned that this omission may make it difficult, if not impossible, to evaluate whether or not the availability of explicit metering information or feedback has an effect on the level of demand response achieved. Accordingly we will direct the respondent IOUs to make a compliance filing discussing the feedback options they will provide to participating customers and how they will evaluate the impact of this feedback on kW reductions. We expect that at a minimum, the IOUs will give customers the opportunity to access this information through

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[19] CCEA Comments on the ALJ's January 10, 2003 Ruling, pp. 7-8.

[20] We believe the payment of the "incentive bonus" will increase the SPP's budget by approximately 3%, based on information provided by ORA in Appendix A.2 to the WG3 Report.

access to a web site or through some more informal mechanism such as the use of an on-site display of load shape data.

5. Technology Treatment Issues

WG3 proposes to offer control or enabling devices to customers on the experimental CPP-V rate using only one type of technology (smart thermostats) and only in Track C. We prefer that the IOUs offer customers a choice of control devices based on the appliances they have and how much they use them. We will direct the respondent IOUs to offer customers on the CPP-V rate in Track A a choice of load control devices based on an inventory of their own appliances. Thus, in addition to testing smart thermostats for heating, ventilation and air conditioning (HVAC) control in Track C, the experimental design should offer to provide load control enabling technologies to customers for at least the following additional appliances: pool pumps and electric water heaters.

We will direct the respondent IOUs to offer these options to customers who have this equipment, as well as air conditioning, and integrate these additions into the existing sample design for Track A. We anticipate that offering these additional control options might have an impact on the starting date for these customers, and we understand that there will be a cost impact, which we intend to cap at $1 million. But, on balance, it is more important to ensure the testing of a full range of technological options for enabling demand response, even if this causes some slippage in our deadline and some cost impact.

6. Adoption of the Alternative Pilots

At this time we will not adopt either of the alternative pilots. We regard both alternatives as early stage proposals, which require more detail prior to adoption.

The IMServ-sponsored T&D Control Pilot, which would offer customers T&D credits for reducing T&D costs, is not confined to residential and small commercial customers who are the focus of this decision, but really addresses the combined WG2 and WG3 customer base. It is very large, arguably not a pilot. It requires more detailed development, and a commitment by this Commission to move towards a T&D incentive-based program, which we believe to be premature based on the state of this record.

We do see some merit in testing the demand response capabilities of a full scale system (comparable to that proposed by Invensys), with the following capabilities:

- Ability to control multiple customer appliance loads based on customer programming.
- Customer ability to override any price or emergency signal.
- Ability to receive and send signals related to pricing conditions, electricity load levels at the house, status of selected appliance loads (on or off), and load drops achieved.
- Capability of handling either pricing or load curtailment signals.
- Capability of confirming the level of load reduction achieved within 1 hour of a price or emergency signal (confirmation for both the operator of send of the signal and the receiving customer).
- Capability of using existing communication lines into the home to send and receive signals (e.g., existing cable or phone lines).

We will direct the respondent IOUs to develop a plan to evaluate the impacts of this type of control system by proposing a method to integrate the installation of these devices at a representative sample of homes during the later stages of this pilot. We envision the IOUs procuring this technology in the fall of

2003, integrating the system with the current utility billing system in the winter of 2003, installing the devices in the spring of 2004, and measuring the impacts of these systems in the fall of 2004. The IOUs should develop a draft plan based on this guidance by June 2003, seek comment on the plan from others participating in WG3, and then file and serve the final plan by July 1, 2003. The budget for the incremental costs of this plan should not exceed $1 million. We will direct the Energy Division to review this plan and budget and then make a recommendation to the ALJ on whether the utilities should proceed to implement the plan as presented.

7. SPP Timing Issues

We keenly appreciate the respondent IOUs' and other parties' efforts to develop and implement the pilot before the start of this summer (or by June 1, 2003), but we caution that it is more important to get things right – especially the decisions that must still be made about the design of the dynamic tariffs and the necessary customer education efforts. We would prefer that the IOUs consider offering SPP participants at least a one-month period to get adjusted to the new dynamic rates, perhaps through the presentation of an old bill and a new bill for the first month, than expecting customers to both understand and adjust to the new rates and enabling technologies on the day that the new meters are installed. Accordingly we ask that the IOUs make every effort to make the June 1 date, but we understand that July 1 may be more realistic. After they have analyzed the net effects of the SPP changes mandated in this decision, we will require the IOUs to file a compliance filing containing a revised pilot schedule.

B. Legislative Mandates

This decision also addresses the Commission's compliance with three legislative measures that address demand response programs and policy.

1. Public Utilities Code Section 393

Under this existing law, the Commission is required to conduct a pilot study of the residential and small commercial customers of each electrical corporation, where the rate level established in subdivision (a) of Section 368 is no longer in effect, to determine the relative value to ratepayers of various information, rate design, and metering innovations for helping residential and small commercial customers better manage their electricity use. (Pub. Util. Code § 393.)

Section 393 requires that such study contain a review and net benefit comparison of several approaches, including the retrofit or replacement of existing meters with meters having real time capability; retrofit or replacement of existing meters with TOU meters that distinguish and measure peak and off-peak energy use; and the replacement of residential and small commercial meters with meters that facilitate the offering of hourly real time pricing. The study must answer discrete questions about the impact of varying degrees of enhanced usage data on customer usage behavior (Section 393(b)(1) through (6)). Finally, the study must meet certain conditions: participation must be limited to a small sample, comprising less than 3% of the electric utility's customers (Section 93 (c)(1)); participating customers must reflect a variety of climate zones and socioeconomic circumstances (Section 393(c)(2)); no customer is required to participate in the study (Section 393 (c)(3)); offerings must be identical among participating electric corporations, although some alternative offerings are allowable (Section 393 (c)(4) and the Commission may alter the pilot study if it finds that it is in the public interest to do so (Section 393 (c)(5)); and all interested energy service providers and equipment manufacturers are to be included in the design and implementation of the pilot study (Section 393 (c)(6)). Finally, Section 393 (f) prescribes technical specifications to be met in carrying out the study, including the requirement, rooted in customer privacy concerns, that information based upon customer data not be used for any commercial purpose without the express authorization of the customer (Section 393 (f)(7)).

The parties who participated in crafting the SPP believe that the proposed pilot generally fulfills the requirements Section 393 specifies for a dynamic pricing pilot. And while the SPP does not implement each feature of the legislation as written, these parties believe it does fulfill the general objectives of the legislation, consistent with the Commission's authority under the legislation to alter the pilot in certain circumstances.[21] For the reasons stated below, we agree.

While the SPP does not test hourly real-time pricing, as mandated by Section 393 (a)(3), the absence of an hourly market makes such a pilot test infeasible at this time; the SPP does test CPP and TOU meters, the latter a requirement of Section 393(a)(2). The information treatments to be included in the SPP will generally provide valid randomized customer use data, as required by Section 393 (b).

The SPP, as approved, will meet most of the conditions outlined in Section 393 (c). The number of participating customers is limited and does not exceed 3% of the respondent IOUs' customers, as required by Section 393 (c)(1). The SPP participants will be selected from comparable geographic areas, from a variety of climate zones, and from a range of socioeconomic circumstances. There will be control groups. Thus the SPP meets the conditions required in

[21] WG3 Report, Section 2.1.

Section 393(c)(2). No randomly selected customer who agrees to participate in the SPP (and who will receive an "appreciation bonus") will be required to participate in the pilot study beyond Summer 2003, due to the nature of the recruitment and opt-out features adopted in this decision, thus enhancing the voluntary aspects of pilot participation. (Section 393 (c)(3).) To the extent the SPP may be perceived to be less than fully voluntary, it is our judgment in authorizing this pilot, that the adopted enrollment approach is in the pubic interest (Section 393 (c))5)). The SPP offerings of the respondent IOUs are very similar and allow for comparison of data and results, as required by Section 393 (c)(4). Interested energy service providers and equipment manufacturers have fully participated in the WG3 process, have contributed meaningfully to the SPP, and have presented alternative pilots, although none of these alternatives is adopted in Phase 1. Although this outcome does not meet the literal terms of Section 393 (c)(6) requiring inclusion of such parties in the design and implementation of the pilot, nonetheless the Commission is authorized in Section 393 (c)(5) to alter the pilot study in this manner if it finds such an outcome is in the public interest. We have done so in this decision.

Section 393 requires that the study data be available to the public and that the data be provided in a way that does not reveal customer-specific information (Section 393 (e)). We will impose this condition on the respondent IOUs.

And, while the SPP does not meet all of the precise technological standards specified in Section 393(f), we believe it is in the public interest in this instance not to be quite as prescriptive, and to give WG3 some flexibility in this area. However, consistent with Section 393(f)(4), we will require that any meter installation done as part of the SPP not compromise customer or worker safety or the integrity or accuracy of the meter. And consistent with Section 393 (f)(8), in order to ensure customer privacy, we will mandate that information based upon customer data derived from the SPP not be used for any commercial purpose.

2. Senate Bill 1976

Noting the existing legislative requirement embodied in Pub. Util. Code § 393, a more recent legislative mandate (SB 1976) enacted in 2002, requires the CEC, in consultation with the this Commission, to report to the Legislature and the Governor by March 31, 2003, regarding the feasibility of implementing real-time, critical peak, and other dynamic pricing tariffs for electricity in California for a variety of customer classes (not just residential and small commercial classes), as strategies that can either reduce peak demand or shift peak demand load to off-peak periods (SB 1976, Sec. 2.) The record developed and the programs approved in this rulemaking (and the contemporaneous CEC rulemaking) will provide much of the data necessary to make this required report, and we will continue to work to meet our reporting obligation based on these interagency efforts.

3. Public Utilities Code Section 2774.6

Senate Bill (SB) 1790 approved by the Governor on September 15, 2002, added Section 2774.6 to the Pub. Util. Code. § 2774.6 requires the Commission, in consultation with the CEC, to develop a program for residential and commercial customer air-conditioning load control, as an element of each electric corporation's tariffed service offerings paid for with electric rates. The goal of the program is to contribute to the adequacy of electricity supply and to help customers reduce their electric bills in a cost-effective manner. The program may include peak load reduction programs for residential and commercial air-conditioning systems, if the commission determines that the inclusion would be cost-effective.

The funding levels of A/C cycling programs for Edison and PG&E are currently under Commission review in other proceedings. Edison currently has a program in place, and the funding level for the program, which will impact the program's pace, is under review in its Test Year 2003 general rate case. As a result of the Commission's mandate in D.01-04-006, PG&E has filed via advice letter a proposal for a limited participation A/C cycling program for residential and small commercial customers; that matter is currently pending. As noted previously, TURN is urging the Commission to order the IOUs to "ramp up" these efforts as a method of more effectively achieving a "quick win" in the demand response area. In general we agree with TURN's sentiments but had originally limited the scope of this proceeding to exclude A/C cycling programs, due to their being addressed in R.00-10-002. Now that that proceeding has been closed (D.03-01-080, issued February 4, 2003) , we plan, in Phase 2 of this proceeding, to review the contribution that cost-effective A/C cycling programs, as peak load reduction programs undertaken by respondent IOUs, can make in meeting the interagency demand response goals we have articulated in this proceeding. In this way, we also intend to continue complying with newly-enacted Section 2774.6 by augmenting our A/C cycling efforts.

C. Phase 1 Cost Recovery Issues

The WG3 report includes respondent IOUs' comprehensive cost recovery proposal for both large customer (>200 kW) and small customer (<200 kW) demand response programs adopted in Phase 1 of this proceeding. As such, the proposal is not confined to costs associated with the SPP, but also includes demand response tariffs and programs emanating from WG2 which will be addressed in our second Phase 1 decision. The proposal covers cost items directly related to assessing, acquiring, deploying, installing, operating and maintaining advanced metering technologies (including directly-related communications hardware, billing systems, and measurement data collection software enhancements), and all incremental costs of designing, implementing, and marketing all approved programs, tariffs, and pilot studies.[22]

The respondent IOUs request authority to (1) establish regulatory accounts to record incremental one-time and ongoing program costs not currently covered in rates; (2) use established balancing accounts to recover under-collected revenues; and (3) use established balancing accounts to recover customer incentive payments.

Since many SPP-related activities are already underway in order to ensure that the pilot is underway by early Summer 2003, the respondent IOUs proposed in the WG3 Report that the Commission establish a cost recovery vehicle for one time and ongoing incremental operations and maintenance (O&M) and administrative and general (A&G) costs associated with work performed prior to issuance of this decision, authorizing each respondent to create a regulatory account (the Advanced Metering and Demand Response Account, of AMDRA) to record such costs, which would be capped at $1 million for the three respondents combined. Respondents requested that the AMDRA for such pre-decisional expenses be established by ruling issued prior to this decision (WG3 Report, Section 6.2.3).

Following this Phase 1 decision, respondents propose that one-time and ongoing incremental O&M and A&G costs authorized by the Commission be estimated and planned for the next five years. As proposed, the Commission

[22] Working Group 3 Report, Section 6.

would remove or increase the previously approved $1 million cap and allow the IOUs to record additional one-time and ongoing incremental capital, O&M, and A&G costs for approved tariffs and programs, the SPP and any preparatory work necessary to implement future decisions issued in this rulemaking. Each year's recorded O&M and A&G costs would be recovered in the subsequent year via an annual advice letter filing, which effectively adds these costs the IOUs' annual revenue requirement, using adopted cost allocation and rate design parameters.

Respondent IOUs propose that all capital additions be treated as authorized additions to plant and associated annual depreciation expense as authorized additions to the revenue requirement. They note that authorized capital expenditures can be rewarded on a cost-per-customer basis (e.g., advanced meters), or a total estimated basis (e.g., billing system addition or measurement data collection software).[23] Commission authorized programs that require IOU incentive payments will be recorded in the appropriate regulatory account. Finally, the parties propose that revenue shortfalls (due to events such as load shifting, load reduction, or bill credits) resulting from programs offered to bundled service customers should be recovered from all bundled service customers through each IOU's existing balancing accounts (SDG&E's ERRA; PG&E's ESPBA[24] and TRA mechanisms; and Edison's PROACT).[25]

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[23] See, WG3 Report, Section 6.1.2, fn. 39.

[24] PG&E's EPSBA was changed, and is know denominated EPSMA, pursuant to D.02-12-074.

[25] WG3 Report, Section 6.1.5, fn 40 and fn 41.

We declined to establish AMDRA via ruling issued prior to this decision. While we appreciate the fact that parties felt some lead time activities were required in order to launch the SPP during Summer 2003, we were unwilling to authorize recovery of any such expenditures incurred prior to this decision, even on a capped basis, in the interests of affording the full Commission the opportunity to completely review the SPP's proposed program and tariff features prior to authorizing any cost recovery. The fact that we have modified the proposed SPP in certain respects underscores the essential dilemma posed by respondent's request for approval of cost expenditures incurred prior to issuance of this decision.

Nonetheless, in this decision we will approve the establishment of AMDRA to allow the respondent IOUs to record and recover the incremental, one-time set up and on-going O&M and A&G expenses incurred to develop and implement the demand response programs adopted for both small (<200kW) and large (>200kw) customers in Phase 1 of this proceeding.

We will also adopt the IOUs' cost recovery proposals relative to capital additions, which means that all Phase 1-related capital additions will be treated as authorized additions to plant and associated annual depreciation expense as additions to revenue requirement.

Commission authorized programs that require IOU incentive payments will be recorded in the following regulatory accounts: ERRA for SDG&E, the EPSMA and TRA for PG&E; and the PROACT for Edison.

Revenue shortfalls due to events such as load shifting, load reduction, or bill credits associated with Phase 1 authorized programs, will be recorded in the ERRA for SDG&E, the EPSMA and TRA for PG&E, and the PROACT for Edison.

In all respects our disposition of these cost recovery issues is limited to Phase 1 programs. Further, in no event are the respondent IOUs authorized to spend more than $12 million in connection with the programs authorized in this decision. This amount reflects the additional costs required to implement our mandated changes to the $9.6 million SPP, specifically 1) the additional technology treatments added to Track A; 2) the full-scale system technology testing to be integrated into the SPP; and 3) the $100 per customer appreciation bonus.

D. SPP Tariff Design Issues

Following issuance of the WG3 Report, the ALJ asked the parties to provide additional information about the range of expected bill impacts (in $ per month) for residential customers who participate in the SPP.[26] Respondents were to provide these estimates assuming no actions by the customers, and then assuming a 30% reduction in usage or shift from on peak consumption to the off peak period. Respondent IOUs provided this information in a supplemental response on January 21, 2003.[27]

Using a database of typical PG&E residential customer usage characteristics, the IOUs prepared illustrative bill impacts for a representative range of "low," "typical," and "high" usage residential customers. Currently residential customers are billed for electric energy using a five-tiered rate design,

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[26] ALJ's Ruling Regarding the WG3 Report and Certain Other Procedural Issues, Question 6, p. 4.

[27] "Supplement to Joint Response of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company to January 10, 2003 Administrative Law Judge Ruling," filed January 21, 2003.

and the rates in tier five are significantly higher than those in tier one. This current rate design complicates the rate design process for pilot residential CPP and TOU tariffs. For this reason, the IOUs' bill analysis used two distinct approaches: the "clean sheet" method and the "supplemental adjustment" method. Both approaches have pros and cons.

The clean sheet method creates pilot CPP and TOU tariffs using only baseline and non-baseline rate tiers. The supplemental adjustment approach maintains the existing five-tiered rates, but applies an on-peak surcharge and off-peak discount adjustment to these rates. Both rate design approaches attempt to achieve revenue neutrality for the average residential customer. The benefit of the clean sheet approach is that it simplifies rates as part of the pilot design. The benefit of the supplemental adjustment approach is that it maintains the effects of existing tiered prices for residential electric usage, while providing a method of implementing the same CPP and TOU rate design for the SPP across all three IOUs' service territories. Both approaches are designed to minimize bill impacts due to a rate change from the existing rates to two time period TOU and CPP experimental rates, assuming no change in electricity consumption (however the supplemental adjustment approach is slightly more successful in doing so). Both approaches also seek to provide customers at least a 10% bill reduction assuming a 30% shift or reduction in consumption from the peak periods. However, both approaches have certain disadvantages.

The clean sheet rate design approach results in bill reductions for high usage participants (and bill increases to low usage participants) prior to any change in consumption. This is because the TOU rate calculation averages the five tier rates, while seeking to maintain revenue neutrality for the "average" residential customer. The Respondent IOUs assert that this outcome generally conflicts with longstanding regulatory and legislative policy under which high usage residential customers pay significantly higher rates than low usage customers. They argue that the baseline statutes and AB1X together effectively dictate that the residential rate design have an inverted tier rate design with at least three tiers. They also maintain that if a clean sheet approach is adopted for the pilot, most high-usage customers would have a strong preference for the TOU rate, just because it would lower the average rate that they would otherwise pay, without necessarily affecting their usage in response to the new prices.

The IOUs maintain that the supplemental adjustment approach would avoid the effect of eliminating or reducing the current tier structure, but could result in differences in the precise ratios between effective on-peak and off-peak TOU prices, depending on the level of each participant's usage. This might reduce the clarity of the CPP and TOU price signals between customers with different usage levels, and could somewhat complicate future analysis of the SPP results. The supplemental adjustment approach also greatly complicates the presentation of bills to customers, since they would not be able to calculate their bills independently, and some components of their bills will not appear accurate mathematically. The respondent IOUs are in favor of the supplemental adjustment approach because it reduces the need for another control rate[28] in the pilot; simplifies incorporation of any rate changes in each IOU's default residential tariffs that might occur over the course of the pilot; and complements

[28] This control rate would be a single tier, non-TOU tariff that permits disaggregating consumption differences due to rate simplification, versus the differences attributable to the CPP and TOU price signals.

the conservation price signals that are provided by each IOUs' current tiered rates.

We do not necessarily agree with the respondent IOUs' argument that longstanding regulatory or legislative requirements constrain us from adopting the clean sheet approach. Like inverted tier rates, TOU rates with CPP components are also aimed at producing conservation. But in addition to encouraging overall conservation, TOU and CPP rates offer a more refined method to encourage conservation during particular time periods when energy is more costly to deliver. Furthermore, this is a pilot program, essentially an experiment, involving a small number of randomly selected customers. The tariff design adopted in this context does not represent a change in existing Commission rate design or a deliberate departure from existing policy. Given these realities, we opt in favor of the clean sheet approach to tariff design because it allows a test of the CPP and TOU tariffs using a more simplified rate design, thus making the choices for and impacts on customers more clear than they would be otherwise.

While opting for this approach, we will require that the tariffs for all SPP participants, both residential and small commercial[29], be designed to meet the following principles:

First, the tariff should be designed to be revenue neutral for the average residential and small commercial customer.[30]

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[29] We recognize that respondents have not yet submitted pro forma tariffs for the small commercial customers participating in the SPP, but the development of these tariffs should be among the issues considered during the meeting processes outlined in Attachments C and D to this decision.

Second, the approach should be designed to minimize bill impacts due to a rate change from the existing rates to pilot rates, assuming no consumption change.[31] The bill impact to participating customers should not exceed ± 5 % of their current average bill, assuming no change in consumption.

Third, the tariff should provide the customer a meaningful incentive for shifting load, consistent with respondent IOUs' claim[32] that the clean sheet approach seeks to provide customers at least a 10% bill reduction assuming a 30% shift or reduction in consumption from the critical-peak or on-peak periods.

We will require respondent IOUs to file advice letters containing such tariffs for the residential and small commercial customers participating in the SPP, consistent with this direction and with Attachments C and D.

V. Monitoring, Reporting, and Procedure for Refinements to Pilot

Though we set the overall parameters for the SPP and its various Tracks in this decision, we expect that, as a result of further market research and implementation efforts, modifications or refinements to the pilot design may be necessary. Parties should raise any such issues formally by filing a motion, fully describing the desired modification or refinement. In order to facilitate the launch of the SPP pilot, we delegate to the Assigned ALJ, in consultation with the WG3 facilitator and staff supporting WG1, the task of authorizing, via ruling, any required modifications or refinements to the pilot program.

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[30] The clean sheet approach is already designed to meet this principle. See Supplement to Joint Response of Respondents, p. 2.

[31] Supplement to Joint Response of Respondents, p. 4.

[32] Supplement to Joint Response of Respondents, p. 4.

In the interests of adequately monitoring the progress of the pilot, we are requiring respondents to file and serve bimonthly reports, as more specifically detailed in Appendices C and D.

VI. Comments on Draft Decision

The draft decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(g), Rules 77.2 through 77.5, and Rule 77.7 of the Commission's Rules of Practice and Procedure.

VII. Assignment of Proceeding

Michael Peevey is the Assigned Commissioner and Lynn Carew is the assigned ALJ in this proceeding.

Findings of Fact

1. The Commission instituted R.02-06-001 to formulate comprehensive policies that will develop demand flexibility as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment; through this collaborative interagency effort with the California Energy Commission (CEC) and the California Consumer Power and Conservation Financing Authority (CPA), the Commission is engaged in policymaking designed to make a broad spectrum of options available to customers who make their demand-responsive resources available to the electric system.

2. Demand response is the ability of an individual electric customer to reduce or shift usage or demand in response to a financial incentive; in this rulemaking we seek to determine whether customers will alter their usage patterns in response to a financial signal that is keyed to system conditions.

3. Working under the direction of interagency decision makers, and with the assistance of a staff facilitator, Working Group 3, a group comprised of

respondents and interested parties who examined residential and small commercial (<200 kW) demand response issues, developed a near-consensus dynamic pricing pilot proposal known as the Statewide Pricing Proposal (SPP).

4. The SPP tests dynamic tariffs for a representative sample of residential and small commercial customers in order to learn more about demand elasticities and customer preferences.

5. The SPP, which will run through the end of 2004, measures the impact of three specific time-varying rates on customer electric consumption and coincident peak demand. The SPP's primary target is residential customers, since earlier experiments show that they demonstrate greater responsiveness to time-varying rates than do commercial customers; however, the SPP breaks new ground by including small commercial customers.

6. In the interests of achieving a statistically representative sample of customers, pilot participants will be drawn from four climate zones statewide, and will include customers of all three respondent investor-owned utilities (IOUs).

7. The 2,575 customers participating in the SPP are assigned to three "tracks" (A, B, and C) that simulate the effects of a large-scale rollout of time-varying rates.

8. In order to provide optimal information, the pilot must test different dynamic rate structures, information treatments, and technology options.

9. The SPP tests three different rate structures: a static time-of-use (TOU) rate, and two types of critical peak pricing (CPP) tariffs, fixed (CPP-F) and variable (CPP-V).

10. The SPP tests the impact of various information presented to participating customers, including the Track B pilot, whose participants will be given

information about the economic and environmental consequences associated with peak power use, and informed of the potential to reduce reliance on a locally-polluting power plant through adoption of a CPP-F tariff.

11. The SPP examines customers' relative responsiveness to dynamic rates with and without various technologies which enable the customer to respond automatically to signals through pre-programming devices.

12. Market research is a necessary part of any pilot design, because it ensures that customers understand the pilot and it also provides insights into their needs and preferences in the interests of fine-tuning the rate, information, or technology aspects of the pilot design.

13. A limited amount of market research is reasonable prior to deployment of the SPP in order to determine how the concept of time-varying pricing can best be explained to customers, to learn what features appeal to them, how to maximize customer acceptance, and what sorts of peak periods and pricing combinations customers will accept.

14. It is also reasonable to conduct concurrent market research to determine whether rate, information, and technology treatments are working optimally during the pilot.

15. Market research conducted at the conclusion of the pilot is valuable in order to obtain the views of customers about their specific experience with the rate, information, and technology treatments.

16. The SPP's market research elements, which include research before, during, and after completion of the program, are reasonable.

17. One of the assumptions that the CPP is designed to test is whether certain low-usage customers have the ability to shift enough load to make program participation cost-effective.

18. Track A of the SPP, as proposed, lacks a robust set of enabling technologies to enhance customer response to a CPP-V rate, and the pilot would be improved by offering Track A customers a choice of additional control devices based on their appliance ownership, as discussed in this decision.

19. SF Co-op will play a crucial role in the implementation of the Track B pilot and the interface with San Francisco customers; however, PG&E is responsible for overall project management of the Track B pilot.

20. The Track B Pilot needs a viable control group, derived from another similarly situated Bay Area community and representative of the Track B participants in that it includes similar households (including a sufficient number of low-income participants) who face the same environmental conditions and/or reside in transmission constrained areas.

21. As proposed, the Track C pilot, which consists of 400 customers currently participating in the pre-existing smart thermostat programs of Edison and SDG&E, tests demand response from customers who voluntarily chose to be in a demand response program. The pilot would be significantly improved by testing alternative recruitment techniques and by ensuring that there is an adequate control group for comparison purposes.

22. The $100 appreciation bonus, to be paid to participants at the end of the four-month commitment period (end of Summer 2003), enhances the voluntary aspects of the SPP's enrollment process at a minimal cost approximating 3 per cent of the entire project cost.

23. The ideal way to achieve the Commission's SPP enrollment goals is to select a statistically random sample and persuade those selected to participate in the SPP voluntarily.

24. Providing additional feedback to customers regarding the kW or dollar impact of their curtailment actions on either a daily or monthly basis, enhances customer satisfaction with the program.

25. In addition to the SPP, two alternative pilot programs were presented by Invensys and IM Serv.

26. The Invensys pilot, designed to test the effectiveness of an advanced, interactive technology, and dispatchable demand response offering, has merit because it advances the range of technologies available to customers to enable demand response; it is desirable to test these enhanced capabilities in a full-scale system as part of a subsequent stage of the SPP.

27. The IM Serv pilot, which offers customers transmission and distribution (T&D) credits, for reducing T&D costs through demand response, requires more detailed development prior to any Commission approval for residential and small commercial customers.

28. With the modifications to the SPP included in this decision, the projected cost of the pilot increases from $9.6 million to approximately $12 million.

29. With the modifications ordered in this decision, the SPP is reasonable.

Conclusions of Law

1. Phase 1 of this proceeding has proceeded as a notice-and-comment rulemaking, and no evidentiary hearings have been held.

2. Track A of the SPP should be modified to include additional control technologies, consistent with the preceding discussion.

3. SF Co-op's request for $142,000 for its role in pilot development, implementation, and analysis, related to the Track B pilot should be denied, since PG&E, as project manager of the Track B pilot, will compensate SF Co-op for its involvement in these efforts under the SPP's proposed budget.

4. The Track B pilot should be modified to include a viable control group including similar households facing the same environmental and/or transmission–constrained conditions.

5. The Track C pilot should be modified to include additional customers through alternative recruitment techniques to ensure a representative sample, as well as ensure an adequate control group.

6. The SPP's enrollment process should meet the following goals: 1) enroll a representative sample of customers to maintain the integrity of the experimental design and ensure the validity of the results; 2) maintain a high level of customer satisfaction; 3) promote retention of the participants for at least one summer; and 4) minimize costs.

7. The SPP should provide a $100 "appreciation bonus" to SPP participants at the end of the four-month commitment period (end of Summer 2003).

8. The SPP should be modified to include additional customer feedback on kW and dollar impacts of their program participation.

9. All Tracks of the SPP should include adequate control groups to ensure the statistical validity of the pilot results.

10. Respondent IOUs should develop a plan to evaluate the impacts of a full-scale system comparable to the alternative proposed by Invensys, and shall propose a method of integrating the installation of such devices at a representative sample of homes during the later stages of this pilot, consistent with the discussion in this decision.

11. The IMServ T&D incentive-based pilot programs should not be approved at this time.

12. The SPP will meet most of the conditions outlined in Pub. Util. Code §393 (c), which requires the Commission to conduct a pilot study of the

residential and small commercial customers of each electrical corporation; where it does not precisely conform to the statute, such variations are in the public interest.

13. No randomly-selected customer who agrees to participate in the SPP (and who will receive an appreciation bonus) will be required to participate in the pilot study beyond the Summer of 2003, due to the nature of the recruitment and opt-out features adopted in this decision, thus enhancing the voluntary aspects of pilot participation, consistent with Pub. Util. Code § 393(c)(3). In general, the opt-out nature of the enrollment process ensures that customer participation is voluntary.

14. The record developed and the programs approved provide much of the data necessary to make the report required by Senate Bill (SB) 1976, which requires the CEC, in consultation with this Commission, to report to the Legislature regarding the feasibility of implementing real-time, critical peak, and other dynamic pricing tariffs for electricity in California.

15. The efforts planned in Phase 2 of this proceeding to review the contribution that cost-effective A/C cycling programs can make in meeting peak load reduction targets are part of this agency's compliance with SB 1790, which added §2774.6 to the Public Utilities Code, requiring the Commission, in consultation with the CEC, to develop a program for residential and commercial customer A/C load control.

16. The SPP cost recovery mechanisms proposed for Phase 1 relative to administrative and general (A&G) and operating and maintenance (O&M) costs, capital additions, incentive payments and revenue shortfalls, are reasonable and should be adopted.

17. It is appropriate to cap the total SPP expenditures at $12 million.

18. Respondent IOUs should develop tariffs for all SPP participants, both residential and small commercial, which are designed to meet the principles previously outlined in this decision.

19. The SPP, as modified in this decision, should be approved.

20. The Respondent IOUs should make every effort to develop and implement the SPP no later than July 1, 2003.

O R D E R

IT IS ORDERED that:

1. Within 30 days of the date of issuance of this decision, respondent IOUs shall file and serve a compliance filing containing all of the following modifications, as discussed in this decision:

   a. Their plan for offering additional control technologies to Track A, CPP-V, customers

   b. A summary of their plan to include a representative control group in the Track B pilot

   c. A summary of their proposal to include alternative recruitment techniques to ensure the statistical validity of Track C participation

   d. A summary of the feedback options to be provided to participating customers and how they will evaluate the impact of this feedback on kW reductions

   e. Their plan for additional control groups in all SPP tracks

2. By July 1, 2003, respondent IOUs shall file and serve a final plan for evaluating the demand response capabilities of a full scale system, comparable to that proposed by Invensys, with the specific capabilities outlined in the preceding discussion, as well as a proposed method to integrate the installation of these devices at a representative sample of homes during the later stages of

this pilot. The respondents shall follow the schedule outlined in the decision for all steps prepatory to making the July 1, 2003 filing. The incremental cost of this plan shall not exceed $1 million.

3. The incremental cost of the additional required control technology offerings in Track A of the SPP shall not exceed $1 million.

4. The data resulting from the SPP shall be available to the public and shall be provided in a way that does not reveal customer-specific information. Such information shall not be used for any commercial purpose without the express authorization of the customer.

5. Any meter installation done as part of the SPP shall not compromise customer or worker safety, or the integrity or accuracy of the meter.

6. With the closure of R.00-10-002, the Commission's interruptible rulemaking, the Commission will review, in Phase 2 of this proceeding, the contribution that cost-effective A/C cycling program, as peak load reduction programs undertaken by respondent IOUs, can make in meeting the interagency demand response goals we have articulated in this proceeding.

7. Within 5 business days after the date of issuance of this decision, the respondent IOUs shall each file and serve on all parties of record, advice letters establishing Advanced Metering and Demand Response Accounts (AMDRAs) for the purpose of recording and recovering the incremental, one-time set up and on-going Operating and Maintenance (O&M) and Administrative and General (A&G) expenses incurred to develop and implement, or in reasonable anticipation of implementing, the demand response programs adopted in Phase 1 of this proceeding. The AMDRAs will apply to all customer classes, unless a class is explicitly excluded by the Commission. The revision dates applicable to the AMDRAs shall be as determined in each IOU's annual advice

letter filing or as otherwise ordered by the Commission. The AMDRAs will not have a rate component. The IOUs shall maintain their respective AMDRAs by making entries at the end of each month as follows:

a. A debit entry equal to the UDC's incremental one-time "set up" and on-going O&M and A&G expenses incurred to develop and implement, or incurred in reasonable anticipation of implementing, the following programs being developed in R. 02-06-001: (1) the statewide pricing pilot (SPP) for small customers (under 200 kW), and (2) demand response tariffs and programs for large customers (greater than 200 kW), including:

    1. Market research prerequisite to SPP implementation;

    2. Development of rate, information, and technology treatments for various SPP cells;

    3. Sample design for various SPP cells

    4. Miscellaneous pilot design refinement and implementation activities;

    5. Development of systems for billing and implementing tariffs and programs for large customers; and

    6. Miscellaneous large customer tariff refinement and implementation activities reasonably necessary to ensure timely implementation of large customer tariffs and programs approved in the Phase 1 decision.

b. A debit entry equal to the interest on the average of the balance at the beginning of the month and the balance after the above entry at a rate equal to one-twelfth the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor.

Parties have 10 days to comment on the advice letters, which shall become effective retroactive to the date of filing upon written approval of the Energy Division.

8. Capital additions incurred for Phase 1 programs shall be treated as authorized additions to the respective respondent IOUs' plant and associated depreciation expense as authorized additions to each respective respondent's revenue requirement, and therefore recovered in rates, consistent with the preceding discussion.

9. Incentive payments associated with Phase 1 demand response programs shall be recorded in the appropriate account for each respondent IOU: the ERRA for SDG&E; the EPSMA and TRA for PG&E; and the PROACT for Edison

10. Revenue shortfalls associated with Phase 1 demand response programs offered to bundled service customers shall be recovered from all bundled service customers through each respondent IOU's existing balancing accounts: the ERRA for SDG&E; the EPSMA and TRA for PG&E; and the PROACT for Edison. The total amount recorded in the ADMDRA, the ERRA, the EPSMA and TRA, and the PRACT in connection with the programs authorized in this decision shall not exceed $12 million.

11. For the duration of the SPP, the respondent IOUs shall file bimonthly reports to summarize program progress, as detailed in Attachments C and D.

12. Any necessary modifications or refinements to the pilot design, beyond those authorized in this decision, shall be requested by formal motion, filed and served on all parties of record, consistent with the discussion in this decision. The assigned ALJ, in consultation with the WG3 facilitator, is authorized to make any necessary modifications by ruling.

13. Within 6 working days after the date of issuance of this decision, the respondent IOUs shall each file and serve on all parties of record, advice letters containing all tariffs required to implement the adopted statewide pricing pilot for all participants, both residential and small commercial. These tariffs shall

conform to the technical requirements contained in Attachments C and D of this decision, and shall be designed to meet the following principles:

a. Tariffs shall be designed to be revenue neutral for the average residential and commercial customer;

b. Tariffs shall be designed to minimize the bill impacts due to a rate change from the existing rates to pilot rates, assuming no consumption change. The bill impact to participating customers shall not exceed ± 5 percent of their current average bill, assuming no change in consumption.

c. The tariff shall provide the customer a meaningful incentive for shifting load, or at least a 10 percent bill reduction assuming a 30 percent shift or reduction in consumption from the critical-peak or on-peak periods.

14. The Statewide Pricing Pilot, as modified in this decision, is hereby approved, with a targeted start date of July 1, 2003.

This order is effective today.

Dated ____________________________, at San Francisco, California.

Attachment A

Glossary of Retail Electricity Rate Terms

This glossary is intended to describe terms used in this report only. It is not intended to take the place of existing rate glossaries, such as those put out by the CPUC, the Rate Design Study, EEI, NARUC, or NRRI.

Automatic control technology	Any technology that allows the customer or electric service provider to pre-program a control strategy - for an individual electric load, group of electric loads, or an entire facility - to be automatically activated in response to a dispatch.
Critical-peak pricing (CPP)	A dynamic rate that allows a short-term price increase to a predetermined level (or levels) to reflect real-time system conditions. In a *fixed-period* CPP, the time and duration of the price increase are predetermined, but the days are not predetermined. In a *variable-period* CPP, the time, duration and day of the price increase are not predetermined.
Demand rate	A per-kW rate, typically applied to the peak demand during each month.
Demand response (DR)	The ability of an individual electric customer to reduce or shift usage or demand in response to a financial incentive.
Dispatch	A broadcast signaling the initiation of a control strategy or price adjustment.
Dynamic rate	A rate in which prices can be adjusted on short notice (typically an hour or day ahead) as a function of system conditions. A dynamic rate cannot be fully predetermined at the time the tariff goes into effect; either the price or the timing is unknown until real-time system conditions warrant a price adjustment. *Examples: real-time pricing (RTP), critical peak pricing (CPP)*
Flat rate	A per-kWh rate in which the same price is charged for all hours during a predetermined time period, usually a season or year.
Information	Facts and data that facilitate consumer response to energy prices. 'Basic information' describes a tariff and its potential impact on expected monthly energy costs. 'Technical information' describes technologies that can be used to respond to the tariff. 'Energy information' describes the consumer's energy consumption patterns on an ongoing basis, to help the consumer adjust behavior and infrastructure to reduce monthly energy costs.

Interval meter	An electricity meter or metering system that records a consumer's load profile by storing in memory each consecutive demand interval, which typically consists of a period ranging from 5 minutes to an hour, synchronized to the hour. The meter can be read through a hand-held device (typically monthly) or through a data link to a central metering master station (typically daily).
Notification	Information provided to customers regarding price adjustments or system conditions. 'Day-ahead' notification provides at least 24 hours advance notice. 'Hour-ahead' notification provides at least one hour advance notice.
Price elasticity	A measure of the sensitivity of customer demand to price. Price elasticity is expressed as the ratio of the percent change in demand to the percent change in price; e.g. a 10% load drop in response to a 100% price increase yields a price elasticity of -0.10. 'Own-price' elasticity relates changes in peak period demand to changes in peak period price. 'Cross-price' elasticity relates changes in usage in one period to changes in price in another period.
Rate	The retail price of electricity per-kW demand or per-kWh usage. A rate may vary as a function of usage (tiered rate), demand (demand rate), period of use (time-of-use rate), or as a function of system conditions (dynamic rate).
Real-time pricing (RTP) rate	A dynamic rate that allows prices to be adjusted frequently, typically on an hourly basis, to reflect real-time system conditions.
Revenue neutrality	A regulatory requirement that any alternative rate design must recover the same total revenue requirement as the default rate design, assuming that customers make no change in their usage patterns.
Seasonal rate	A rate in which the price of electricity changes by season.
Smart thermostats	A heating, ventilation and air-conditioning (HVAC) thermostat that: (1) automatically responds to different electricity prices by adjusting the temperature set point or the operation of the HVAC equipment using pre-programmed thresholds that have been specified by the customer; (2) displays energy information and rates, and notifies the customer of rate changes; and/or (3) can be programmed to control devices other than the HVAC system.
System conditions	Any or all of the following: wholesale electricity costs, reliability conditions, environmental impacts, and/or the relationship between supply and demand.

Tariff	A public document setting forth the services offered by an electric utility, rates and charges with respect to the services, and governing rules, regulations and practices relating to those services.
Tiered rate	A rate in which predetermined prices change as a function of cumulative customer electricity usage within a predetermined time frame (usually monthly). Prices in an 'inverted tier' rate increase as cumulative electricity usage increases. Prices in a 'declining tier' or 'declining block' rate decrease as cumulative electricity usage increases.
Time-of-day (TOD) rate	A rate in which predetermined electricity prices vary across two or more preset time periods within a day.
Time-of-use (TOU) rate	A rate in which the price of electricity varies as a function of usage period, typically by time of day, by day of week, and/or by season. *Examples: TOD rate, seasonal rate.*
Time-varying rate	A rate in which prices change or can be changed within a 24-hour period. *Examples: TOD rate, dynamic rate*.

(END OF ATTACHMENT A)

Attachment B

Table 3-2. Sample Design of the Statewide Pricing Pilot

12/04/02

Track A: Random Sampling With Opt Out Design

	Control	**CPP-F**	**CPP-F (Info)**	**CPP-V (SDG&E) (1)**	**Info Only (1)**	**TOU**	**Total**	**Cost**
Residential								
Zone 1	50	120	0	0	0	30	200	
Zone 2	50	120	0	0	0	30	200	
Zone 3	50	120	0	150	100	30	450	
Zone 4	50	240	0	0	0	30	320	
Total	200	600	0	150	100	120	1170	
w/Opt Out	250	750	0	188	125	150	**1463**	**$3,796,875**
Commercial								
<20 kW	50	0	0	60	0	30	140	
>20 kW	50	0	0	80	0	30	160	
Total	100	0	0	140	0	60	300	
w/Opt Out	125	0	0	175	0	0	**375**	**$1,300,000**
All Sectors								
Total	300	600	0	290	100	180	1,470	
w/Opt Out	375	750	0	363	125	150	**1,838**	**$5,096,875**

Tracks B: SF Cooperative

Residential	**Control**	**CPP-F**	**CPP-F (Info)**	**CPP-V (SDG&E)**	**Info Only**	**TOU**	**Total**	**Cost**
PG&E (2)	0	100	100	0	0	0	200	
Total	0	100	100	0	0	0	200	
w/Opt Out	0	125	125	0	0	0	**250**	**$625,000**

Track C: AB 970 Sub-Sample

Residential	**Control**	**CPP-F**	**CPP-F (Info)**	**CPP-V (SDG&E)**	**Info Only**	**TOU**	**Total**	**Cost**
SDG&E (3)	50	0	0	100	0	0	150	
Total	50	0	0	100	0	0	150	
w/Opt Out	62.5	0	0	125	0	0	**188**	**$468,750**
Commercial	**Control (SCE)**	**CPP-F**	**CPP-F (Info)**	**CPP-V (SCE)**	**Info Only**	**TOU**	**Total**	**Cost**
<20 kW	50	0	0	60	0	0	110	
>20 kW	50	0	0	80	0	0	130	
Total	100	0	0	140	0	0	240	
w/Opt Out	125	0	0	175	0	0	**300**	**$900,000**
All Sectors								
Total	150	0	0	240	0	0	390	
w/Opt Out	188	0	0	300	0	0	**488**	**$1,368,750**

SUMMARY

	Control	**CPP-F**	**CPP-F (Info)**	**CPP-V (SDG&E)**	**Info Only**	**TOU**	**Total**	**Cost**
Total Sample Size	**450**	**700**	**100**	**530**	**100**	**180**	**2,060**	
Total Sample Size with Opt Out	**563**	**875**	**125**	**663**	**125**	**150**	**2,575**	
Total Variable Cost								**$7,090,625**
Total Fixed Cost (4)								**$2,500,000**
Grand Total								**$9,590,625**

Notes:

(1) Entries are to be spread across various climate zones.

(2) This row corresponds to a proposal made by the San Francisco Cooperative and will be based on an opt out random sample located in the Hunter's Point/Potrero Hill districts of San Francisco and West Oakland/Richmond.

(3) These customers will be selected on an opt-out basis from the existing AB970 sample, which has an opt-in structure.

(4) Total fixed cost includes:
0.80 million: Market Research
0.75 million: Impact Evaluations
0.65 million: Project management
0.30 million: Refinement of Treatments and Sample Design

(END OF ATTACMENT B)

ATTACHMENT C
Experimental Residential Time-Of-Use Tariffs

The purpose of the Experimental Time-Of-Use tariffs (TOU tariffs) is to measure customers' demand response and experience with time differentiated energy rates.

1.1. **Effective Date:** June 1, 2003 through December 31, 2004.

1.2. **Applicability**

1.2.1. These tariff schedules are applicable to all residential bundled service customers in Southern California Edison (Edison), Pacific Gas and Electric (PG&E), and San Diego Gas and Electric (SDG&E) service territories.

1.2.2. Service under these experimental tariffs is restricted to the customers that are randomly selected by the utility.

1.3. Customer Recruitment

1.3.1. Customers shall be randomly selected based on the sample design filed with the Commission.

1.3.2. Customers shall have the option to decline to participate in an experimental tariff.

1.3.3. Customers that remain on an experimental tariff schedule for four consecutive months shall receive an incentive payment of up to $100 for their participation in this experiment.

1.3.4. Customers shall have the option of returning to their applicable tariff schedule.

1.3.5. Customers selected for an experimental tariff schedule may be required to have either a central air conditioner, electric water heater or pool pump on their premises compatible with the utility installed technology (control) treatment.

1.4. **Time-Of-Use time periods**

1.4.1. These experimental tariffs shall be designed with two time periods, an on-peak and off-peak period. The *on-peak period* shall be from 1 p.m. to 6 p.m. weekdays, and the *off-peak period* all hours outside the on-peak period for weekdays including weekends and holidays.

1.4.2. Seasons are defined as the existing utility standard summer and winter seasons.

1.5. Experimental Rate Treatments

1.5.1. The TOU rates shall be designed using the “clean-sheet” approach following the principles outlined in this order.

1.5.2. The low-price ratio TOU rate treatment shall have an on-peak to off-peak price ratio between 1.3 and 1.7.

1.5.3. The high-price ratio TOU rate treatment shall have an on-peak to off-peak price ratio between 1.8 and 2.5.

1.5.4. These tariffs should be designed so that customers can clearly find the total off-peak and on-peak prices they are being charged.

1.5.5. An adjustment shall be applied to customers’ electricity bills so that the average electricity bill at current rates does not increase or decrease by more than 5% for those customers that do not change their usage pattern. Utilities should meet and confer with all parties at a public meeting to discuss options for calculating this adjustment within 10 days of this draft order. Utilities should then file, within 6 working days of the final decision, their recommended final TOU tariffs and the associated adjustment option, including an estimate of the likely bill impacts for low and high usage customers assuming no shift in usage patterns.

1.6. Information Treatment

1.6.1. Customers shall be provided with explicit price information on their monthly bills, the total on-peak and off-peak rates and monthly consumption during each time period.

1.6.2. Each customer must be provided with educational information on the experimental tariff and options for reducing on-peak usage. A copy of this information shall be filed with the Commission’s Energy Division.

1.6.3. Each customer must complete a customer information survey, which may include, but not be limited to, questions about number of members in the household, income, end-uses, dwelling size, and age.

1.6.4. Customers participating on an experimental tariff shall receive energy usage and cost information via bill inserts, printed literature, fax, e-mail, pager, radio and/or web based content accessed via the Internet.

1.7. **Metering**

1.7.1. Each customer shall be provided with the necessary metering equipment for billing and load monitoring, at no cost to the customer.

1.8. **Monitoring and Reporting:**

1.8.1. Bi-monthly reports shall be filed every two months with the Energy Division and the staff of the California Energy Commission for the duration of the experiment, which should include information on:

1.8.1.1. The number of customers participating in the experiment and the number of customers who have chosen to opt-out on a monthly basis;

1.8.1.2. Monthly operating expenses and capital expenditures;

1.8.1.3. The number and timing of any critical peak pricing periods called during the previous two months.

1.8.1.4. Information on how customers are responding to the experimental rates, including:

(a) Summaries of any oral or written feedback from customers;

(b) Information available on the level of peak reductions being achieved on a per household or regional basis;

(c) Information on load control technology performance (failure rates, customer complaints);

(d) Feedback on how information treatments are being received by customers.

1.8.1.4.1 Identification of significant problem(s) being encountered in the implementation of the pilot which require Commission attention and or action.

1.8.1.4.2 Interval meter data for participating customers spanning the previous two months of energy usage in a comma delimited electronic file format. The files should include customer ID #'s, strata, dates and daily readout of clean fifteen minute interval data to allow for an analysis of aggregate usage trends**.**

(END OF ATTACHMENT C)

ATTACHMENT D
Experimental Residential Critical Peak Pricing Tariffs

The purpose of the Experimental Time-Of-Use tariffs & Critical Peak Pricing (TOU-CPP tariffs) is to measure customers' demand response and experience with critical peak price signals sent by utilities on a day ahead basis in an attempt to reduce consumption and overall costs during forecasted periods of high peak demand and costs for the system.

1.1. **Effective Date:** June 1, 2003 through December 31, 2004.

1.2. **Applicability**

- 1.2.1. These tariff schedules are applicable to all residential bundled service customers in Southern California Edison (Edison), Pacific Gas and Electric (PG&E), and San Diego Gas and Electric (SDG&E) service territories.
- 1.2.2. Service under these experimental tariffs is restricted to the customers that are randomly selected by the utility.

1.3. Customer Recruitment

- 1.3.1. Customers shall be randomly selected based on the sample design filed with the Commission.
- 1.3.2. Customers shall have the option to decline to participate in an experimental tariff.
- 1.3.3. Customers that remain on an experimental tariff schedule for four consecutive months shall receive an incentive payment of up to $100 for their participation in this experiment.
- 1.3.4. Customers shall have the option of returning to their applicable tariff schedule.
- 1.3.5. Customers selected for an experimental tariff schedule may be required to have either a central air conditioner, electric water heater or pool pump on their premises compatible with the utility installed technology treatment.

1.4. **Time-Of-Use time periods**

1.4.1. These experimental tariffs shall be designed with two time periods, an on-peak and off-peak period. The *on-peak period* shall be from 1 p.m. to 6 p.m. weekdays, and the *off-peak period* all hours outside the on-peak period for weekdays including weekends and holidays.

1.4.2. Seasons are defined as the existing utility standard summer and winter seasons.

1.5. Experimental Rate Treatments

1.5.1. The TOU rates shall be designed using the “clean-sheet” approach following the principles outlined in this order.

1.5.2. The low-price ratio TOU rate treatment shall have an on-peak to off-peak price ratio between 1.3 and 1.7.

1.5.3. The high-price ratio TOU rate treatment shall have an on-peak to off-peak price ratio between 1.8 and 2.5.

1.5.4. These tariffs should be designed so that customers can clearly find the total off-peak and on-peak prices they are being charged.

1.5.5. A baseline adjustment shall be applied to customers’ electricity bills so that the average electricity bill does not exceed +/-5% with no change in electricity consumption. Utilities should meet and confer with all parties at a public meeting to discuss options for calculating this adjustment within 10 days of this draft order. Utilities should then file, within 6 working days of the final decision, their recommended final CPP/TOU and TOU tariffs and associated adjustment option, including an estimate of the likely bill impacts for low and high usage customers assuming no shift in usage patterns.

1.5.6. A fixed Critical Peak Price (CPP-F) rate shall also be tested as part of the rate treatments in combination with a low and high price ratio TOU-tariffs. The UDCs shall propose CPP rate level that meets the rate design conditions outlined in this order. The CPP/TOU rate should be designed such that the CPP rate is between 5 and 10 times the off peak rate to approximate the range of cost increases that have been experienced on a critical peak day with high temperatures and tight supplies.

1.5.6.1. Activation of the CPP rate shall be limited to no more than 15 days per calendar year during on-peak hours, twelve of those days shall be during the summer period and three during the winter period.

1.5.6.2. A CPP event should be limited to five (5) hours per event for up to 3 consecutive days.

1.5.6.3. Each customer shall be notified by 5:00 p.m. the day prior to implementation of the CPP event.

1.5.7. A variable Critical Peak Price (CPP-V) rate shall be tested as one of the rate treatments in combination with a low and high price ratio TOU-tariffs. The UDCs shall propose CPP rate level that meets the rate design conditions outlined in this order

1.5.7.1. The critical peak hours for the variable CPP shall be limited to 90 hours per calendar year.

1.5.7.2. The critical peak start hour, duration, and the end hour may vary with each notification, but the duration of the critical peak event shall not exceed four consecutive hours.

1.5.7.3. Each customer shall be notified of the critical peak start hour and duration at least four hours prior to a critical peak.

1.6. Information Treatment

1.6.1. Customers shall be provided with explicit price information on their monthly bills, including the total critical peak, on-peak and off-peak rates applicable to the customer and monthly consumption during each time period.

1.6.2. Each customer must be provided with educational information on the experimental tariff and options for reducing on-peak usage. A copy of this information shall also be provided to the Commission's Energy Division.

1.6.3. Each customer must complete a customer information survey, which may include, but not be limited to, questions about number of members in the household, income, end-uses, dwelling size, and age.

1.6.4. Customers participating in an experimental tariff shall receive energy usage and cost information via bill inserts, printed literature, fax, e-mail, pager, radio and/or web based content accessed via the Internet.

1.7. Metering

1.7.1. Each customer shall be provided with the necessary metering equipment for billing and load monitoring, at no cost to the customer.

1.8. Technology Treatments

1.8.1. For the Variable Critical Peak Pricing treatment customers should be offered a choice of control devices based on the customer's appliances inventory and usage level. In addition to testing smart thermostats for HVAC control in homes where these devices have already been installed, the experiment design should offer to provide load control devices for pool pumps and electric water heaters. The customer should have the choice of installing one of these three control strategies or to install none of them and rely on manual control strategies.

1.9. **Monitoring and Reporting:**

1.9.1. Bi-monthly reports shall be filed every two months with the Energy Division and the staff of the California Energy Commision for the duration of the experiment, which should include information on:

1.9.1.1. The number of customers participating in the experiment and the number of customers who have chosen to opt-out on a monthly basis;

1.9.1.2. Monthly operating expenses and capital expenditures;

1.9.1.3. The number and timing of any critical peak pricing periods called during the previous two months.

1.9.1.4. Information on how customers are responding to the experimental rates including:

1.9.1.5.

a) Summaries of any oral or written feedback from customers;
b) Information available on the level of peak reductions being achieved on a per household or regional basis
c) Information on load control, technology performance (failure rates, customer complaints);
d) Feedback on how information treatments are being received by customers;

1.9.1.6. Identification of significant problem(s) being encountered in the implementation of the pilot which require Commission attention and or action.

1.9.1.7. Interval meter data for participating customers spanning the previous two months of energy usage in a comma delimited electronic file format. The files should include customer ID #'s, strata, dates and daily readout of clean fifteen minute interval data to allow for an analysis of aggregate usage trends

(END OF ATTACHMENT D)